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BEFORE THE ARIZONA CORPORATION COMMISSION

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COMMISSIONERS

2007 FEB 16 P 12: 17

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
GARY PIERCE

AZ CORP COMMISSION
DOCUMENT CONTROL

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-05-0816
IN THE MATTER OF THE INQUIRY INTO THE FREQUENCY OF UNPLANNED OUTAGES DURING 2005 AT PALO VERDE NUCLEAR GENERATING STATION, THE CAUSES OF THE OUTAGES, THE PROCUREMENT OF REPLACEMENT POWER AND THE IMPACT OF THE OUTAGES ON ARIZONA PUBLIC SERVICE COMPANY'S CUSTOMERS.	DOCKET NO. E-01345A-05-0826
IN THE MATTER OF THE AUDIT OF THE FUEL AND PURCHASED POWER PRACTICES AND COSTS OF THE ARIZONA PUBLIC SERVICE COMPANY.	DOCKET NO. E-01345A-05-0827

ARIZONA CORPORATION COMMISSION STAFF'S REPLY BRIEF

February 16, 2007

Arizona Corporation Commission
DOCKETED
FEB 16 2007
DOCKETED BY nr

Christopher C. Kempley, Chief Counsel
Janet Wagner, Senior Staff Counsel
Charles Hains, Attorney
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

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Arizona Corporation Commission Staff ("Staff") hereby files its responsive brief in this matter. This brief primarily attempts to respond to the arguments against Staff's recommendations set forth by the other parties in their respective closing briefs. To the extent that this brief does not address any particular issue, Staff relies upon its discussion of those issues set forth in its opening brief, filed on January 22, 2007.

I. THE COMMISSION SHOULD REJECT APS' PROPOSED "ATTRITION ADJUSTMENTS" AND SHOULD INSTEAD RELY ON TRADITIONAL COST OF SERVICE PRINCIPLES TO ESTABLISH APS' RATES.

In this case, APS has argued that the Commission must grant APS its entire rate request if the Company is to avoid financial ruin. This request was made clear in the testimony of APS witness Steven Wheeler. (Wheeler Rebuttal Test., hereinafter referred to as "Wheeler Rebuttal", Ex. APS-2 at 2, 3, 9, 18, 25; *see also* Tr. at 4240-43; 4264-65). APS bases this argument on the following assertions, all of which are disputed, unreliable, or meritless: 1) APS claims that the Commission is *required as a matter of law* to consider the projected impact of a rate decision on APS' financial criteria, 2) APS claims that these forecasts show that, from a quantitative view, APS will not meet the required credit metrics to maintain an investment grade credit rating under either the Staff or RUCO proposals, 3) APS claims that the cost of customer growth is greater than the revenues generated by that growth, thereby causing the Company's rates to be inadequate. This brief will subsequently discuss each of these contentions in turn.

A. The Commission is not required *as a matter of law* to use future projections to establish rates.

APS claims that the Commission is *required as a matter of law* to consider the projected impact of a rate decision on APS' financial criteria. In support of this assertion, APS cites *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), and *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n of West Virginia*, 262 U.S. 679 (1923). These decisions in large part address whether the federal constitution requires states to follow any specific method when setting rates. These decisions specifically reject that conclusion and instead hold that, for purposes of determining whether a rate decision is confiscatory for purposes of federal due process, it is the "end result" that is significant, not the specific method.

These cases identify three factors to consider in determining whether a rate decision produces rates that satisfy federal constitutional standards:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

Bluefield, 262 U.S. at 693. Contrary to APS' assertions, these cases do not identify any one method for satisfying these factors and are careful to point out that whether a particular rate decision constitutes just compensation "depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, *having regard to all relevant facts* . . . ." *Id.* at 692 (emphasis added).

APS argues that the Commission cannot ascertain whether proposed rates will be adequate "to maintain and support its credit" or "to raise the money necessary for the proper discharge of its public duties" without considering the impact of those proposed rates in some future period. (APS' Br. at 9-10). APS then produces forecasts of the future period of its choosing, claims that these forecasts show that it will suffer a credit-rating downgrade unless its entire rate request is granted, and suggests that the Commission should disregard all other evidence *except* the forecasts. (Wheeler Rebuttal at 2, 18; Dittmer Surrebuttal Test., hereinafter referred to as "Dittmer Surrebuttal", Ex. S-37 at 4-5). In APS' view, its financial forecasts of future periods become the automatic and binding formula for determining its revenue requirement. This result is the complete opposite of the holdings of *Hope* and *Bluefield*, which urge a consideration of all relevant factors and expressly disavow a mechanistic reliance on any single formula.

In other words, APS believes that the Commission *is required as a matter of law* to establish rates exclusively by reference to APS' financial ratios, which are based upon *forecasts*. APS' argument implies that federal constitutional standards *require* the use of a future test year. (*See* Tr. at 4199-4200). APS not only fails to cite any federal cases to specifically support this theory but also fails to reconcile it with Arizona law. In fact, Arizona cases suggest that rates should be set by reference to an *historic* test year and that a utility's rate base must be established by reference to the fair value of its property that is "used and useful" in providing public service. *See* Ariz. Const. art. XV, § 14.

Certainly, Commission decisions must comport with federal constitutional standards. However, the method advocated by APS is not required by the federal constitution, and is also at odds with the Arizona Constitution. As the Arizona Supreme Court has stated,

> It is clear, therefore, that under our constitution as interpreted by this court, *the Commission is required to find the fair value of the company's property and use such finding as a rate base for the purpose of calculating what are just and reasonable rates.* The *Hope* case cannot be used by the Commission. To do so would violate our constitution. The statute under consideration in that case prescribed no formula for establishing a rate base. While our constitution does not establish a formula for arriving at fair value, *it does require such value to be found and used as the base in fixing rates. The reasonableness and justness of the rates must be related to this finding of fair value.*

Simms v. Round Valley Light and Power Co., 80 Ariz. 145, 151, 294 P.2d 378, 382 (1956) (emphasis added). As the *Simms* court noted, "fair value" focuses the Commission's analysis on the "time of inquiry." *Id* at 151, 153, 294 P.2d at 382, 383. Other Arizona cases also recognize that the fair value concept is related to the "time of inquiry." *See Arizona Corp. Comm'n v. Arizona Public Service Co.,* 113 Ariz. 368, 370, 555 P.2d 326, 328 (1976) (stating that utility is entitled to reasonable return on the fair value of its properties at time that rate is fixed); *Arizona Corp. Comm'n v. Arizona Water Co.*, 85 Ariz. 198, 202, 335 P.2d 412, 414 (1959) (stating that fair value is to be determined as of time of inquiry when determining a utility's rate base and rate of return thereon); *Consolidated Water Utils.,* *Ltd. V. Arizona Corp. Comm'n*, 178 Ariz. 478, 482-83, 875 P.2d 137, 141-42 (App. 1993) (stating that rates are based on value of corporation's properties at time rate is fixed).

The underlying policy for establishing rates by using historic cost-of-service principles instead of forecasts was articulated by RUCO witness Hill, who acknowledged that it is not unusual for the relationship between the number of customers and the amount of utility plant necessary to serve customers to vary after rates are set. (Tr. at 2148). Mr. Hill stated the following:

> But my point arguing against the company's position is that *we don't need to stuff all those costs in the current rate case because we don't know what those costs are*. And I don't know of any utility, regulatory body that lives completely in the future and tries to discern what the relationship, regulatory relationships are in the future.

(Tr. at 2149 (emphasis added); *see also* Tr. at 2150-51). In short, there are both legal and policy considerations that support the use of an historic adjusted cost-of-service test year as the basis for establishing rates. The Commission should not depart from those principles in this matter.

B. The projections provided by APS in this case are not helpful and should be disregarded.

APS has prepared various financial projections that purport to establish APS' financial ratios for 2007, 2008, and 2009 under APS', Staff's, and RUCO's proposals, respectively. APS claims that these forecasts show that, from a quantitative view, APS will not meet the required credit metrics to maintain an investment grade credit rating under either the Staff or RUCO proposals.

The Arizona Constitution entrusts the Commission with exclusive authority over all matters related to ratemaking. *See Arizona Corporation Comm'n v. State ex rel. Woods,* 171 Ariz. 286, 292, 830 P.2d 807, 813 (1992). Although the Commission is not required to use APS' projections as the basis for setting rates, it may certainly consider such information if the Commission were to determine that the information is helpful. In the context of this proceeding, however, the financial projections provided by APS are not helpful and should be disregarded.

First, APS' projections have been prepared on a *total company* basis. (Dittmer Supplemental Test., hereinafter referred to as "Dittmer Supplemental", Ex. S-39 at 7). These forecasts of "total company operating results" include APS' FERC-regulated transmission operations. *Id.* Although these FERC-regulated assets are normally not relevant to retail rate proceedings, the Company's use of projections prepared on a total company basis makes them so, because they would include the effects of any "under-earning" on the Company's transmission assets. *Id.*

APS witness Wheeler acknowledged that APS is planning on filing a transmission rate case at FERC, (Tr. at 351), thus affirming that APS believes that it is currently under-earning on its transmission investment. According to Staff witness Dittmer's rough calculations, it appears that some fairly significant amount of transmission rate relief is justified, and thus at least part of APS' "total company" earnings shortfall is apparently caused by under-earnings on the Company's transmission assets—operations that are regulated by FERC, not by the Commission. (Dittmer Supplemental at 9). Reliance on "total company" financial metrics that are known to include an earnings shortfall from "non-jurisdictional" business operations is not an accurate measure by which to set rates.

Importantly, in a FERC transmission rate proceeding, FERC will not examine whether state retail rates have remedied any earnings shortfall related to transmission investment. *Id.* at 9-10. Instead, FERC will conclude that the Commission's retail rates were established to allow the Company to recover its *retail cost-of-service* on a stand-alone basis and will then proceed to evaluate the need for *transmission rate relief* on a stand-alone basis. *Id.* Furthermore, Decision No. 67744 creates a transmission cost adjustor, which APS may use outside the context of a rate case to pass through to retail customers the costs of transmission rate increases. *Id.* at 9.

APS would have the Commission remedy any earnings shortfall on its FERC-regulated assets through its so-called "attrition adjustments" that it builds upon its "total company" earnings and coverage ratios shortfall. *Id.* This result would very likely lead to double recovery with Arizona ratepayers paying for the same alleged earnings shortfall once through retail rates and again through FERC transmission rates. This result is hardly fair and serves as an example of the problems inherent in relying on unaudited "total company" forecasts presented comparatively late in the case.

In addition, because APS submitted these projections so late in the proceeding, they have not been subjected to the full rigors of a rate case audit and are therefore unreliable. An examination of the procedural schedule in this case will serve to illustrate this point. APS' rate application was filed on January 31, 2006; thereafter, Staff and interveners were allowed approximately 199 days to prepare direct testimony. (April 5, 2006 Procedural Order, Dkt. No. E-01345A-05-0816). During this period of time, Staff issued approximately 630 data requests, reviewed the Company's schedules, testimony, and discovery responses, and conducted interviews and on-site inspections. Because APS' current rate request was based upon an adjusted historic test year cost-of-service, the vast majority of Staff's discovery and analysis was focused on "annualized" and "normalized" historic operating results. As a result of Staff's discovery and audit, Staff identified numerous adjustments to the Company's adjusted historic test year cost-of-service, several of which have been conceded by the Company. Very little discovery or analysis was directed to the Company's post-test-year projections; for again, the Company's projections were *not* the basis of its request for rate relief.

APS' rebuttal testimony, which shifted APS' focus from traditional cost-of-service to financial forecasts, was filed on September 15, 2006; thereafter, Staff and interveners were allowed approximately 12 days to prepare surrebuttal testimony. Less than two weeks is woefully inadequate to conduct the necessary discovery and to evaluate issues and related data presented for the first time in rebuttal. (*See* Tr. at 4197-99). As Staff witness Dittmer explained, auditing forecasts is a complex undertaking that is susceptible to as much dispute as any typical rate case issue. (*See* Tr. at 4192-95). Even with only limited time and data, Staff has pointed out in surrebuttal and supplemental testimony significant problems in the presentation of the Company's forecasts.

<u>C.</u> <u>Staff's audit shows that APS' current rates appropriately recover the Company's non-fuel costs.</u>

APS claims that the cost of customer growth is greater than the revenues generated by that growth, thereby causing the Company's rates to be inadequate. (APS' Br. at 12-13). This claim is not supported by the evidence.

1. Transmission Costs.

First, as discussed earlier, it is important to recognize that transmission cost recovery is a matter regulated by FERC. Therefore, if APS believes that its current transmission rates do not adequately recover its FERC-jurisdictional cost-of-service, APS should pursue transmission rate relief at FERC. If FERC were to grant APS' request, the Company would be able to pass on the transmission rate increase to retail customers through its transmission cost adjustor. (*See* Dittmer Supplemental at 9).

2. Capacity Costs.

Next, it is important to review the structure of the *existing* PSA as it relates to APS' recovery of its incremental generation costs. Demand charges are often excluded from adjustor mechanisms because growth in retail sales will often be available to offset the incremental demand costs incurred to serve new load. (Dittmer Direct Test., hereinafter referred to as "Dittmer Direct", Ex. S-37 at 11). APS' existing PSA, however, permits APS to pass through not only energy charges but also demand charges. (Dittmer Surrebuttal at 11). The purchased capacity paid for through the demand charges replaces the need to build generating capacity that would otherwise be required to meet customer growth. *Id.* APS' significant reliance on purchased power contracts to meet its significant growth, in conjunction with its PSA, provide great assurance that there is no significant earnings attrition for APS' "production function" investment.

Therefore, any attrition related to production costs (generation) is significantly addressed through the recovery of demand charges in the PSA, and growth in retail margins is available to a much larger extent to meet cost increases related to growth in distribution plant and to recover cost increases caused by inflation. *Id.* at 12. This feature of APS' existing PSA significantly undermines APS' claim that it will suffer attrition. Furthermore, party is seeking to amend this feature of APS' PSA in this proceeding.

3. Distribution and Other Costs.

APS contends that rate relief related to fuel and purchased power recovery will not be adequate to allow it to avoid a credit rating downgrade. Staff, by contrast, believes that APS' need for rate relief is driven by the under-recovery of fuel costs. (Tr. at 4197-99). This conclusion is supported by the results of Staff's rate case audit. *Id.* at 4178-80, 4197-99.

Staff's audit shows that, except for fuel costs, rates have been adequate to cover non-fuel items. *Id.* at 4178-80. Staff's prefiled surrebuttal position, for example, includes an increase of $193.5 million for fuel costs and an offsetting *decrease* of $2 million for non-fuel items. *Id.* at 4179. RUCO's surrebuttal position, although not identical to Staff's, shows an increase of $280 million for fuel costs and a decrease of $69 million for non-fuel items. *Id.* Thus, the two parties who customarily conduct thorough rate case audits have concluded that existing rates adequately recover the Company's non-fuel costs. (*See* Dittmer Surrebuttal at 19). Contrary to APS' claim, there is ample and credible evidence that, on a "normalized" basis, APS is *not* experiencing attrition on its ACC-jurisdictional non-fuel cost of service.

4. Rate relief that addresses the Company's rising fuel costs is sufficient relief at this time.

To summarize, if the source of APS' alleged under-earnings is its transmission rates, APS may seek rate relief from FERC and may pass through to its retail customers any increases in transmission rates through its transmission cost adjustor. Increases in capacity costs due to customer growth are fully addressed by the structure of APS' PSA, which includes the recovery of demand charges. Finally, the Staff rate case audit in this matter shows that, outside of fuel and purchased power costs, APS' cost of service has been—and continues to be—adequately recovered within existing base rates. (Dittmer Surrebuttal at 19).

That leaves the recovery of fuel costs, which Staff's recommendations have generously addressed. Although the Company's rate application is premised upon a test year ending September 30, 2005, Staff accepted the Company's proposal to establish the base cost of fuel and purchased power by reference to a forecast of calendar year 2006. (Antonuk Direct Test., hereinafter referred to as "Antonuk Direct", Ex. S-28 at 33; Antonuk Surrebuttal Test., hereinafter referred to as "Antonuk Surrebuttal", Ex. S-29 at 2-10). Staff believes that its recommended base cost for fuel and purchased power is reasonable, especially in conjunction with Staff's proposed PSA.

Staff has recommended a number of changes to the PSA, such as the addition of the forward component and the elimination of various existing features, such as the 90/10 sharing mechanism, the $776 million cap, and the 4 mil bandwidth. (Antonuk Direct at 33, 37; Antonuk Supplemental at 2-8). Staff believes that these modifications will minimize the possibility for large deferrals in the future.

Finally, Staff believes that the rating agencies should recognize that the Commission's actions both this year and last show a substantial degree of regulatory support. A review of the Commission's recent decisions regarding APS is instructive:

1) Decision No. 68437 moved up the adjuster reset from April 1, 2006 to February 1, 2006. The reset date was also modified to February 1st for all subsequent resets. In addition, the $776 million cap was stayed pending the completion of APS' current rate case.

2) Decision No. 68685 approved an interim surcharge of 7 mils in order to address APS' 2006 under-recoveries of fuel and purchased power costs.

3) Decision No. 69184 approved the continuation of the interim 7 mil surcharge until the completion of the rate case.

In the context of these decisions, it is difficult to consider Staff's proposed modifications to the PSA as anything but a concerted regulatory response to ensure that APS will have an opportunity to timely recover its fuel and purchased power costs. Staff also believes that the rating agencies should view the modified PSA, if adopted by the Commission, as yet another sign of regulatory support.

5. APS' November 28, 2006 response to Chairman Hatch-Miller's letter is not a basis for concluding that earnings attrition is occurring due to customer growth.

Late in the proceeding, APS produced a letter that is designed to demonstrate that it costs more to serve a new APS customer than an existing APS customer. The letter was produced after the cut-off date for discovery and thus Staff has not had an opportunity to review the data, calculations, or assumption underlying the letter. Nonetheless, Staff witness Dittmer noted the following shortcomings:

> 1) The document appears to have examined growth in *gross* plant in service amounts to serve customers. It fails to capture the fact that, for instance, *net* production plant has actually been declining in most years. The growth in the depreciation reserve serves to offset the higher costs of new *gross* plant added to serve new customers.
>
> 2) The document fails to recognize that many expenses remain relatively fixed notwithstanding growth in customers and sales. Thus, the "economies of scale" have not been considered anywhere as an "offset" to the purported attrition occurring with new customer growth.
>
> 3) There can often be other "offsets" to serving new customers, such as the post test year federal income tax savings that will occur with the increase in the production tax credit beginning in 2007. No party has recommended including these savings within the adjusted test year cost of service.
>
> 4) The Company's assumption of the marginal cost of debt underlying new plant investment is significantly overstated—by over 100 basis points.
>
> 5) The document does not distinguish which gross plant additions are being added to achieve operational savings. It is reasonable to assume that at least a portion of the projected plant additions are being constructed to achieve operating expense savings—which are not included within the Company's response.

(Tr. at 4174). In short, the data contained in this letter have not been subjected to scrutiny. However, even without the benefit of discovery and analysis, Staff has pointed out many concerns—if not outright flaws—in the document. It should be rejected as a basis for supporting the Company's attrition request.

II. COST OF CAPITAL

There are three steps to determining a utility's cost of capital in a rate proceeding: 1) determining the appropriate capital structure, 2) determining the appropriate cost of debt, and 3) estimating a reasonable cost of equity. As between Staff and APS, the first two steps of this inquiry are not in dispute. The third step—determining the appropriate cost of equity—is the cost of capital issue that remains at issue.

To estimate the cost of equity, Staff used three recognized methodologies: the Discounted Cash Flow Model ("DCF"), the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings Method ("CE"). (Parcell Direct Test., hereinafter referred to as "Parcell Direct", Ex. S-8 at 3-4). Each of these methods was applied to two different sets of proxy groups: one developed by Staff witness Parcell and another developed by APS witness Avera. *Id.* Based upon this analysis, Staff witness Parcell concluded that APS' cost of equity falls within a range of 9.5–10.75 percent. *Id.* at 4. Staff recommended the mid-point of this range, 10.25 percent, as the cost of equity for APS. (Parcell Direct at 4; Tr. at 3251-52).

APS claims that Staff's recommendation suffers from a "downward bias" that results from "flawed analysis."[1] (APS' Br. at 21-22). APS also attempts to cast doubt upon the validity of the DCF method, alleging that certain limitations of the DCF model make it unsuitable for capturing the long-term expectations for the utility industry. *Id* at 20. By contrast, Staff believes that the DCF model is a useful tool in estimating the cost of equity.

First, it is undisputed that regulatory commissions across the country continue to consider and rely upon the DCF model. (Tr. at 3236-37). Indeed, each of the three cost of capital witnesses in this

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[1] Staff witness Parcell discusses in detail these alleged errors and explains why these criticisms are without merit. (*See* Parcell Surrebuttal Test., hereinafter referred to as "Parcell Surrebuttal", Ex. S- at 5-10).

proceeding performed a DCF analysis, although each assigned a different degree of reliance to his DCF results. While RUCO witness Hill relied heavily upon his DCF results, APS witness Avera almost entirely discounted his DCF results. Staff witness Parcell's analysis, by contrast, represents a sort of middle ground: while Mr. Parcell's cost of equity analysis relies upon his DCF results, he does not rely upon them *exclusively*. (Parcell Direct at 4, 32; Tr. at 3245). Furthermore, although Mr. Parcell's DCF results range from 9.0-10.0, his analysis focused on the upper end of that range, *i.e.*, 9.5-10.0, in order to recognize the additional risk factor posed by APS' current bond rating. (Tr. at 3240, 3259-60). Staff's approach is therefore a measured one, appropriately considering its DCF results along with the results of the other models and the varying degrees of APS' risk. *Id.* at 3259-60.

It is worth noting that the DCF results from all three cost of capital witnesses were relatively close. *Id.* at 2168. It is also true that, in this proceeding, the DCF model produced lower cost of equity estimates than that of the various other cost of equity estimation models. The fact that the DCF results are consistently lower than those produced by other models—in and of itself—is not a valid reason to disregard the DCF results, especially when those results are similar among three witnesses who do not necessarily share a common conceptual orientation. (*See* Tr. at 2168).

APS argues that, because industry analysts expect lower returns for utilities, the DCF model becomes unreliable. (*See* Tr. at 2169). This contention is disputed on the record. For example, RUCO witness Hill reached a contrary conclusion:

> We know that the DCF Model is simply the dividends divided by the stock price plus the growth rate. Well, if investors are really bearish on utilities, what will happen? The price will go down....And in that model, dividend over price, dividend won't change but the price gets smaller. That means that ratio will be larger and the cost of capital, as indicated by the DCF, will go up.
>
> So, Dr. Avera's representation to you that the DCF is unreliable, *i.e.* too low, because investment companies are bearish on utilities is exactly the wrong advice. If investment companies were bearish on utilities, the price would go down, the dividend would go up, and the DCF would give a high number....

Id. Staff witness Parcell also disputed the Company's contention that the DCF model contains a downward bias, albeit for somewhat different reasons. In his discussion of the effects of overall economic and financial conditions, he drew the following conclusion:

> It is apparent that capital costs are currently low in comparison to the levels that have prevailed over the past three decades. In addition, even a moderate increase in interest rates, as well as other capital costs, would still result in capital costs that are low by historic standards. Therefore, it can reasonably be expected that cost of equity models, such as the DCF, currently produce returns that are lower than was the case in prior years.

(Parcell Direct at 12; *see also* i*d.* at 9-10).

Even aside from the DCF model, APS claims that it has demonstrated the alleged "downward bias" in Staff's cost of equity estimate by reference to various industry benchmarks. (*See* APS' Br. at 21). Specifically, APS' brief cites the following sources:

> [T]he rates of return on common equity authorized electric utilities by regulatory commissions were *10.69* percent for electric utilities in the second quarter of 2006 and *10.57* percent for the year as of September 15, 2006. Using the groups of firms identified as most comparable to APS by Mr. Hill and Mr. Parcell, the two groups of firms were authorized on average ROE of *10.89* percent and *10.91* percent respectively. Second, Value Line reported as of September 1, 2006, that electric utilities as a whole are anticipated to earn a return of at least *10.5* percent from 2007 through 2011. And Lehman Brothers projected that in 2007 the electric utility industry would be granted allowed rates of return that averaged *11.3* percent in order to keep pace with the market as a whole.

(APS' Br. at 21 (emphasis added) (citations omitted)). As an initial matter, Staff does not agree that reference to these alleged "benchmarks" is necessarily helpful or relevant to determining APS' cost of capital. (*See* Parcell Surrebuttal at 4). Setting those concerns aside, however, it is nonetheless curious that APS would claim that these "benchmarks" somehow undermine Staff's cost of equity estimate. All except one (11.3) are in the mid to upper tens (10.69, 10.57, 10.89, 10.91, 10.5); for the most part, they are closer to Staff's estimated cost of equity (10.25) than they are to APS' (11.5). (*See* Parcell Surrebuttal at 2-3). Furthermore, APS overlooks other evidence in the record that suggests that APS' own investment advisers expect a return on the broad stock market that is "well below" ten percent. (Tr. at 2054-57). This information is consistent with Staff witness Parcell's conclusion that, due to the current level of capital costs, cost of equity models are likely to produce results that are low by historic standards. (Parcell Direct at 12; Parcell Surrebuttal at 5).

One may be tempted to conclude that Staff's recommended cost of equity estimate is identical to that adopted for APS in its last rate case and therefore merely maintains the status quo. Staff witness Parcell, however, explained why this conclusion is incorrect:

> Q. Your recommendation, sir, of a return on equity of 10.25 percent is the same as the company's allowed rate of return at the present time; correct?
>
> A. Yes and no.
>
> Q. It's a simple question. Yes?
>
> A. It's yes and no, because the rate of return is the overall rate of return. The 10.25 percent agreed to in the 2003 case, which was settled in 2005, was based upon a common equity ratio of 45 percent and a cost of debt of 5.8 percent. The cost of debt has gone down to 5.4, and the common equity ratio has gone from 45 percent to 54.5. So the other two components have both moved [in] [sic] the company's favors since that time. So the maintenance of 10.25 with a lower cost of debt and a higher equity ratio is an improvement.
>
> Actually, in the calculation 1 think it's a—7.8 was the rate of return agreed to last time, and 1 recommended 8.05. That's 25 basis points higher than total cost of capital, 25 more basis points than total rate base, and that's real money.

(Tr. at 3285-86).

APS also claims that Staff has ignored the principles of *Hope* and *Bluefield*. As discussed earlier, Staff disagrees with APS' assertion that the Commission is legally required to consider financial projections in order to satisfy the principles of *Hope* and *Bluefield*. Nonetheless, a review of Staff's testimony clearly demonstrates that Staff considered these principles in developing its recommendations. (Parcell Direct at 6-8; Tr. at 3258-62, 3265-69, 3273-84). APS also argues that Staff failed to consider the potential impact of its recommendations upon the Company's bond rating. Contrary to APS assertions, Staff witness Parcell clearly considered APS' current ratings as well as various rating agency statements in arriving at his recommendation. (Tr. at 3270-711; 3282-88; 3291-92; 3294-3303; 3305-06).

APS contends that Staff's recommendation is inconsistent with the testimony of Staff witness Rogers, which was filed in a recent case. In his surrebuttal testimony, Mr. Parcell addressed these allegations:

> [M]y review of Mr. Rogers' testimony reveals to me that our conclusions are very similar. In his testimony, Mr. Rogers recommended, for Paradise Valley Water Company...a return on equity range of 9.6 percent (DCF results) to 10.0 percent (CAPM results) plus a 0.6 percent "upward financial risk adjustment" which was designed to recognize the financial risk associated with the 36.7 percent common equity ratio of the utility. In the case of Paradise Valley Water, the subject utility had more leverage and thus financial risk than the proxy group. In the case of APS, on the other hand, the opposite situation occurs, since APS has a higher equity ratio and thus less financial risk than the proxy group.

(Parcell Surrebuttal at 11). APS cites limited portions of Mr. Rogers' testimony, thereby overlooking the fact that Mr. Parcell's 10.25 percent recommendation for APS is quite comparable to Mr. Rogers' 10.4 percent recommendation. *Id.* at 12.

Finally, Staff notes that APS' recommended 11.5 percent cost of equity includes an adjustment for flotation costs. Specifically, APS has increased its cost of equity estimate by twenty basis points as a flotation cost adjustment (Parcell Direct at 37). Staff opposes this adjustment. A utility should only be allowed to recover from ratepayers its actual and quantifiable levels of issuance costs. *Id.* APS has not demonstrated that it has actually incurred any issuance costs. *Id.*

In addition, the market-to-book ratios of Dr. Avera's electricity distribution group are sufficiently high as to make a flotation adjustment unnecessary and inappropriate, because any common stock issuance would actually increase book value of existing stockholders. *Id.* Finally, the revenue requirement impact associated with APS' flotation cost adjustment is nearly $8 million annually. *Id.* As Staff witness Parcell noted, this is an excessive level of flotation costs for ratepayers to bear. *Id.*

In summary, Staff's cost of equity estimate is based upon recognized models that were applied in a measured and reasonable manner. The Commission should therefore adopt Staff's recommended cost of equity for purposes of determining APS' rates.

III. PENSION EXPENSE

As Staff witness Dittmer explained, layering APS' proposed five-year accelerated "catch up" adjustment on top of the FAS 87-determined pension expense, which already incorporates a "catch up" provision, will likely lead to a double or over-recovery of the underfunded pension liability. FAS 87 effectively includes a "catch up" provision for situations wherein the trust fund significantly underperforms relative to earlier projections or when other previously expected assumptions change over time. In fact, a significant element of the Staff-proposed FAS 87-determined pension expense consists of such a "noted "catch up" provision. Thus, if rates are established based upon FAS 87-determined pension accruals—as Staff recommends—the presently-calculated shortfall will be recovered over time, albeit not over the accelerated five-year period that APS recommends.

In its brief, APS presents a number of arguments in favor of its proposal to accelerate the recovery of pension expense. None of APS' arguments, however, convincingly explains how APS plans to address the regulatory liability that its proposal will create. Staff witness Dittmer described this issue in his testimony:

> I still have problems with just how the company's plan would even work, how it could mechanically work. *Where are you going to get the cash to refund customers?*
>
> You can see the money going into the trust. No doubt about that. I believe your accountants and Mr. Brandt have testified that if the company's proposal is adopted, you increase the expense for regulatory purposes, you increase the check that you write to the pension trust. I understand that for the first five years. That's pretty easy.
>
> Now we get ready to refund the customers. *You can't take the money out of the trust. You got to take it from someplace else. And the company has already complained about cash flow problems. This proposal doesn't help anything in the short run, the five-year period, and it exacerbates the cash flow problems in years*

> *6 through 15,* in my opinion, from what I've seen so far. I do not know how you cannot create a cash flow problem with this proposal.

(Tr. at 4217-18 (emphasis added)). APS' proposal will not improve its cash flow position in the short term, because APS has committed to funding its pension trust with the incremental rate recovery that its proposal would generate. APS' proposal will also worsen its cash flow position in the long term, because APS will have to refund the regulatory liability to its customers. APS' proposal is not in the best interests of either the Company or its customers, and the Commission should therefore reject it.

IV. CASH WORKING CAPITAL

Staff and APS disagree over the cost-of-service elements that should be reflected in the cash working capital calculation. APS contends that both depreciation and deferred taxes generate additional investment that should be reflected in rate base as part of the allowance for cash working capital. (APS' Br. at 42). APS also contends that interest expense should be excluded from the development of a lead-lag study. *Id.* Finally, APS opposes Staff's exclusion from the lead-lag study of the amortized expenses of pre-paid insurance costs and nuclear fuel. *Id.* at 44.

A. Depreciation and Deferred Taxes.

Both depreciation and deferred taxes are non-cash expenses. Neither requires APS to make a cash outlay in order to meet the day-to-day expenses incurred in providing utility service. APS argues that there is a gap between the time when customers are credited for their payment of these expenses and the time when customers actually pay for them. (APS' Br. at 42). But APS ignores the fact that this "gap" is a phenomenon of regulation. In other words, APS' crediting (through a rate base deduction) of customers' payments of these expenses does not require an actual cash outlay. This point is well illustrated by the arguments set forth in RUCO's brief in this matter:

> APS' arguments lack merit, as they both are based on the erroneous assumption that a lead lag study and the resulting cash working capital requirement is intended to measure *regulatory* lag. In fact, the purpose of a lead lag study is to measure the period of time between when service is rendered and when cash is received or dispersed.

> APS claims that depreciation should be included in cash working capital because "rate base is reduced during the benefit period when the expense is incurred," but depreciation is recorded some 37 days before APS recovers the revenues related to depreciation. However, the premise on which APS' argument is based is flawed. Rate base is *not* reduced each month when depreciation is booked. Rather, rate base is a purely regulatory concept, and is recomputed only at the time of a rate case. Thus, when APS books depreciation expense in October 2006, it does not result in an immediate decrease to rate base and does not result in a lower revenue requirement in November 2006. Instead, the revenue APS collected in December 2006 was based on the undepreciated plant levels as of December 2002, the end of the test year in APS' last rate case.

(RUCO's Br. at 10-11 (emphasis in original) (citations omitted)).

Furthermore, assuming for purposes of argument that the lead-lag study were expanded to analyze the collection of "depreciation expense," it should also symmetrically and equitably be expanded to consider the lag in the payment of construction expenditures. If the study were thus expanded, plant in service/rate base would be reduced for the construction expenditures recorded as "gross plant in service" at test-year end that have not yet been "paid for" by APS. Stated simply, APS cannot selectively choose to expand the study to consider "non-cash" expenses, such as depreciation and deferred income tax expense, unless it is willing to consider "offsets" to such components, such as test-year end plant in service not yet "paid for" by APS.

In considering this issue, it is helpful to recall the definition of cash working capital: cash working capital is defined as the amount of cash needed by a utility to pay the day-to-day expenses incurred in providing service as compared to the timing of the utility's collection of revenues for those services. (Dittmer Direct at 33, 36). Therefore, the items that appropriately fall within the scope of a lead-lag study are those transactions that relate to the *day-to-day payment of expenses incurred* in providing utility service. *Id.* at 33, 36-37. Neither depreciation expense nor deferred income tax expense meets this definition; therefore, the Commission should exclude these items from the calculation of cash working capital.

. . .

. . .

B. Interest Expense.

The ratemaking formula provides for the recovery of interest expense. (Dittmer Direct at 43). Ratepayers pay for service on a monthly basis, yet the periodic payment of interest expense to debt holders typically occurs at somewhat extended intervals, *i.e.,* quarterly or semi-annually. Fairness requires the lead-lag study to recognize that the Company has the use of these funds for the extended period between their collection from ratepayers and the Company's payout of interest to debt holders. *Id.* For these reasons, interest expense should be included in the lead-lag study.

APS argues that, if the lead-lag study considers interest expense, then it should also consider the lag in the receipt by equity investors of their return. (APS' Br. at 43). In fact, as Mr. Dittmer noted in his direct testimony, common stockholders are typically paid dividends quarterly after the company has "earned" such return. If the lead-lag study were to be expanded to consider the lag in the payment of dividends, the result would be an even larger rate base deduction, not a smaller one as suggested by APS. Thus, Staff's approach of only including interest expanse in the lead-lag study—consistent with all Commission decisions on this issue for at least twenty years—is, if anything, conservative and should be upheld.

C. Amortized Prepaid Insurance and Nuclear Fuel Expenses.

Staff has excluded amortized prepaid insurance and amortized nuclear fuel expenses from the lead-lag study because they are non-cash expenses. Accordingly, they should be excluded from the lead-lag study for the same reasons that other non-cash expenses should be excluded. (*See* Dittmer Direct at 33-42).

D. Arizona Precedent.

Finally, it is worth noting that the Commission has unambiguously concluded that non-cash items, such as depreciation expense and deferred tax expense, should be excluded from lead-lag studies. The Commission has also concluded—just as unambiguously—that interest expense should be included in lead-lag studies. (*See* Dittmer Direct at 28-29). Furthermore, the Company has not offered any new arguments to explain why these issues should be reconsidered. Staff recommends that the Commission follow its established precedent and adopt the adjustments to APS' lead-lag study proposed by Staff.

V. INVESTMENT TAX CREDITS

The investment tax credits ("ITCs") at issue in this proceeding result from APS' filing of amended federal income tax returns. (*See* Dittmer Direct at 100). Specifically, these prior federal income tax returns were amended in order to claim additional ITCs related to plant that had been constructed in the mid to late 1980s. *Id.* During the discovery phase of this proceeding, APS described the tax return associated with this issue as expected and imminent. *Id.* at 103.

Staff has proposed that the Commission recognize as a rate base offset all of the unamortized ITC balance related to plant not fully depreciated. (Dittmer Surrebuttal at 43). The description of and rationale for this adjustment are fully addressed in the testimony of Staff witness Dittmer. (*See* Dittmer Surrebuttal at 43-45).

In its brief, APS implies that the Commission has disposed of this issue in a prior decision. (*See* APS' Br. at 45). Decision No. 58644, which adopted a 1994 settlement agreement, provided that the then-remaining (*i.e.*, as of 1994) unamortized ITCs related to years before 1991 would be fully amortized below the line over the subsequent five years. (*See* Dittmer Direct at 105). APS now argues that the Commission's 1994 decision, which addressed then-remaining unamortized ITCs, somehow anticipated and dealt with the treatment of the ITCs at issue in this proceeding, approximately twelve years later.

Staff witness Dittmer anticipated APS' argument in his direct testimony:

> *It is possible that if these recently claimed ITCs had been known and quantified* at the time of the 1994 agreement that such ITCs would have simply been lumped in with other unamortized ITCs on APS' balance sheet existing at that time and amortized over the same five year period as other ITCs existing at that time.

> *In light of all the uncertainty surrounding how these ITCs might have been recognized in prior regulatory proceedings*, the di minimus amount at issue, as well as all the other arguments for and against ratepayer participation in benefits from the transaction, I am recommending that the costs to achieve the ITC saving be deducted from the total revenue requirement benefits expected to be realized. I am proposing that one-half of the remaining benefits or savings resulting from the transaction be used as a rate base offset—as had been the precedent for ITCs prior to 1994.

Id. at 105-06 (emphasis added)). Staff witness Dittmer subsequently amended his recommendation somewhat in order to avoid any possible Internal Revenue Code normalization violations—the *only* argument raised by APS on this issue within its rebuttal testimony.

As a result of the revision to Staff's original adjustment to eliminate a possible violation of IRC normalization requirements, Staff has recommended in surrebuttal that far less than half of the newly-determined ITC savings be allocated to ratepayers. (Dittmer Surrebuttal at 43). Thus, Staff's surrebuttal testimony recognizes the uncertainty surrounding possible IRC normalization violations and proposes a regulatory treatment that is very generous to the Company but nonetheless provides some benefit to ratepayers. Staff's proposal on this issue is reasonable and should be adopted.

VI. BARK BEETLE REMEDIATION

In its brief, APS correctly notes that the disputes regarding recovery of bark beetle remediation costs relate to the time period over which the Company may defer these costs. (APS' Br. at 53). APS contends that the plain meaning of Decision No. 67744 authorizes the Company to defer bark beetle remediation costs beginning January 1, 2005, a full three months before that decision was issued. APS' construction of Decision No. 67744 requires a retroactive application of that order. APS, however, has not—because it cannot—identify any provision in that decision that *expressly* indicates that the Commission intended *retroactive* application.

APS relies upon the portion of Decision No. 67744 that allows it to defer "reasonable and prudent direct costs of bark beetle remediation that exceed the *test year* levels of tree and brush control." Using the cited text, APS goes on to argue that "the language indicates that a full year of cost recovery was intended." *Id.* at 54. The plain and simple fact is that APS has clearly deferred even more than a full year of bark beetle remediation costs—beginning in April 2005 and as projected through the end of 2006.

Ultimately, the Commission can tell the parties what it intended within the language of Decision No. 67744. As Staff witness Dittmer testified, "in all my years of negotiating and reviewing the impact of accounting deferral orders, I do not ever recall an order being applied retroactively from the implementation date of the order *unless explicitly set forth within the order.*" (Dittmer Surrebuttal at 41 (emphasis added)). It is noteworthy that APS has not disputed this claim, nor has it provided any citation to suggest that it has ever observed the retroactive application that it seeks in this case.

VII. SUNDANCE UNITS

APS has included in its cost of service the operations and maintenance expense associated with its recently acquired Sundance Combustion Turbine Units ("Sundance"). Staff opposes the recovery in rates of certain estimated Sundance O&M expenses that indisputably will not actually be incurred for many years into the future. (Dittmer Direct at 95).

Staff acknowledges that APS generally normalizes maintenance costs for its mature generating units by calculating a multi-year historical average of such costs, adjusted for inflation over time, to arrive at a normalized level of maintenance expense. *Id.* at 98. APS claims that this method is akin to a "long-accepted Arizona regulatory practice" and that Staff has not offered any reason to reject it. (APS' Br. at 56). This criticism is inaccurate. Staff has specifically and repeatedly identified the rationale underlying its Sundance adjustment: the maintenance costs in question will not actually be incurred for many years into the future—well past the time when rates set in this proceeding are likely to be in effect. (Dittmer Direct at 95-100).

APS also claims that Staff's approach to PWEC maintenance costs is inconsistent with its approach to Sundance maintenance costs. Specifically, APS notes that Staff has not objected to APS' proposal to recover one-twelfth of its twelve-year forecast of maintenance expenses for PWEC. APS fails to note, however, that it has used a unique approach for normalizing Sundance maintenance expense. Specifically, APS reaches far into the future to incorporate planned Sundance maintenance expenditures when developing its Sundance normalization adjustment. For the PWEC units, APS admittedly uses a twelve-year forecast, but importantly, APS is already incurring a portion of such maintenance expense. The PWEC situation contrasts factually with the Sundance situation, wherein again Staff notes that the maintenance expenditures will not occur until many years in the future.

In testimony, Staff witness Dittmer described the risk for double recovery that APS' proposal presents. *Id.* at 98-99. If this proposal were adopted, the Commission creates the risk that ratepayers will pay for these costs both now and then again through future rates. (Dittmer Direct at 99; Tr. at 4224-25). If the Commission were to accept APS' proposal, it should at least require APS to recognize as a current period expense amounts collected in rates for Sundance's non-routine maintenance expense and to concurrently establish a regulatory liability on its balance sheet. (Dittmer Direct at 99; Tr. at 4226). This accounting treatment will ensure that ratepayers will not be charged twice for the same expense. (*See* Dittmer Direct at 99-100).

VIII. LOBBYING EXPENSES

Pursuant to the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA"), utilities are required to record lobbying costs below the line, where there is a presumption of non-recovery. (Dittmer Direct at 114-15). In this case, contrary to USOA guidelines, APS charged a number of its lobbying costs above the line to administrative and general expense accounts, and these lobbying costs were therefore included in its proposed test year cost of service. *Id.* at 116. As the Company itself states in its post hearing brief, "*[t]he Company itself already allocated* certain costs between 'below-the-line' lobbying activities for which the Company is not seeking recovery and 'above-the-line' Public Affairs activities . . . ." (APS' Br. At 69 (emphasis added)). It is inappropriate for the Company to disregard the requirements of the USOA by recording these costs in this way.

APS is *required* to record all lobbying costs below-the-line, and its disregard of this requirement should be disturbing. (Dittmer Direct at 114). Recording lobbying expenses properly, *i.e.,* below-the-line, does not preclude APS from seeking cost-of-service recognition for them in this or subsequent rate cases. *Id.* at 117. It does, however, require APS to propose a specific adjustment to its operating income in order to seek rate recovery of these costs. *Id.* Proper accounting of these costs will ensure that expenses that are presumed to fall outside of the Company's cost-of-service are not hidden within inappropriate accounts, thereby placing the burden upon Staff auditors to uncover them. For these reasons, the Commission should specifically recognize that APS has failed to recognize the requirements of the USOA and should order APS to appropriately comply with these requirements.

APS also argues that the Commission should permit it to recover certain lobbying expenses in rates. APS cites certain previous Commission orders to support the argument that the Commission has previously allowed lobbying expenses in rates if the utility can demonstrate that the lobbying benefits ratepayers. The cases that APS cites, however, address membership dues or trade industry dues and are therefore not precisely on point.

Staff contends that lobbying expenses should be disallowed as a matter of regulatory policy. (Tr. at 4230-34). Staff witness Dittmer explained the reasons for this well established policy:

> [U]tilities are unique in that they have a certain required service, a regulated service that's not provided by other providers. They wield great power in that respect. And, therefore, as a matter of regulatory policy, I don't think that they should be encouraged to lobby by including that expense in the cost of service.
>
> Now, admittedly some lobbying arguably helps ratepayers, but to try and distinguish what is good lobbying versus bad lobbying becomes a very difficult task. And even so-called good lobbying for ratepayers sometimes comes at a cost to other taxpayers, other constituents, other contractors.
> So just as a matter of regulatory policy, I say just say no to lobbying expenses included in the cost of service.

(Tr. at 4231). The Commission should follow this established policy and exclude lobbying expenses from APS' rates.

IX. INCENTIVE COMPENSATION

APS claims that the incentive compensation issue should focus upon whether APS employee compensation—as a whole—is reasonable, not how that compensation is determined. (APS' Br. at 74). This argument overlooks the fact that the means of determining compensation has a substantial effect upon employee behavior and management decisions.

Ratepayers should not have to bear costs that do not have any associated ratepayer benefit. It is undeniable that APS' stock-based incentive compensation plan is aligned with stockholder—not ratepayer—interests. (Dittmer Direct at 107-08). The specific terms of APS' stock-based incentive compensation programs are driven by the financial performance of Pinnacle West, rather than the operational performance of APS as a public utility. *Id.* at 108. Enhanced earnings levels can sometimes be achieved by short-term management decisions that are not in the interests of ratepayers. *Id.* at 111. The Commission should therefore adopt Staff's proposed disallowance of the costs of APS' stock incentive compensation program.

APS witness Mark Gordon testified in support of APS' overall compensation program, including its stock compensation plan. The alleged benefits of the Company's stock compensation plan identified by Mr. Gordon are cited within the Company's brief. (APS' Br. at 74). Mr. Gordon's testimony in a recent Puget Sound Energy, Inc. ("Puget) rate case contained observations about incentive plans that are based entirely upon financial performance. Specifically, Mr. Gordon's Puget testimony contains the following statements:

> PSE's Goals and Incentive program is more detailed in the specificity of financial and non-financial goals and better communicates the linkage of goal attainment with incentive award opportunity than the majority of broad-based incentive plans at other companies. *Very often, broad-based incentive plans are solely tied to company earnings with no variation for business unit or team performance, and no link to customer and/or service reliability objectives. These types of plans act*

> *more as an end of year" bonus" than a motivational "pay for performance" system driving specified behavior."*

(Ex. S-4 at 7 (emphasis added)). Mr. Gordon's disparaging remarks about incentive compensation plans "solely tied to company earnings" perfectly describe APS' stock compensation plan.

Also of interest, Mr. Gordon's Puget testimony emphasizes that Puget has a stock-based long term incentive plan using common shares of Puget Energy stock, similar to the APS stock compensation plan at issue in this proceeding. However, Mr. Gordon's Puget testimony acknowledges that Puget's stock-based compensation is funded fully by shareholders and is not included within Puget's proposed cost of service. Mr. Gordon's testimony from the Puget case appears to support Staff's incentive compensation adjustment.

X. PROPERTY TAX EXPENSE

APS argues that the Commission should reject RUCO's property tax adjustment, claiming that rates set in this proceeding should be established by considering property tax expense amounts expected to be paid in 2007. Staff continues to support RUCO's property tax adjustment over APS' objections.

In support of this adjustment, Staff notes that APS proposes to reflect *only 2007 property tax expense.* Throughout this proceeding, APS has continually reminded this Commission of the high growth in its service territory in sales. APS, however, fails to propose any increase in margins to the 2007 time period that would offset an increase in projected property tax expense.

Furthermore, APS is inconsistent in its position on property tax expense versus income tax expense. Specifically, APS opposes an adjustment to increase the production tax credit that is *known to occur in 2007* that will result in lower federal income tax expense—by an amount that is nearly identical to the amount of the RUCO property tax adjustment. Stated simply, APS cannot credibly argue for 2007 property tax expense levels while simultaneously arguing against known reductions in federal income taxes. RUCO's proposed property tax adjustment is reasonable and should be accepted.

XI. PALO VERDE ISSUES

A. APS documents and NRC evaluations are virtually the only source for determining the level of the Company's knowledge about the details of its performance.

During 2005, the Palo Verde Nuclear Generating Station ("Palo Verde") experienced a total of eleven planned and unplanned outages. Of these outages, Staff identified four as imprudent. (GDC Report, hereinafter referred to as "GDS Report", Ex. S-45 at 2). APS is therefore responsible for these outages, and ratepayers should not have to bear their costs.

The Company claims that Staff's analysis improperly relies upon NRC documents, INPO evaluations, and Company root-cause reports. The Company contends that these sources analyze Palo Verde's operations with the benefit of hindsight and are therefore irrelevant to determining whether APS was imprudent. However, as Staff witness Jacobs testified, these reports provide vital contemporaneous evaluations by the respective entities that produced them. (Jacobs Surrebuttal Test., hereinafter referred to as "Jacobs Surrebuttal", Ex. S-48 at 15). Reports such as these are routinely considered in prudence evaluations by a variety of regulatory commissions. *Id.*

FERC has relied on both NRC and company documents in determining the prudence of nuclear plant outages:

> The Company is correct that these NRC findings do not translate directly into a finding of imprudence from an economic regulatory perspective... But at some point, surely, a great number of NRC negative comments about a particular plant's management and operations and admissions by Company managers to such conduct become inconsistent with the notion of a prudently managed nuclear plant from any perspective, including economic regulation... [and] these negative comments from nuclear safety regulators ... also provide evidence that can and should be used in reaching an economic regulatory judgment about the prudence of management conduct.
>
> ***
>
> While, considered alone, the admissions of the Company managers about their shortcomings and weaknesses are not quite a confession of imprudence.... They

> nevertheless provide strong evidentiary support for a finding of imprudent management.... It would take tortured logic, indeed, to conclude that the NRC's hyper-critical comments about the Company's management of the plant and the Company's own admission of significant failures and shortcomings described in this report are consistent with reasonable and prudent managerial conduct from either a safety or economic regulatory perspective.

Connecticut Yankee Power Co., 84 FERC ¶ 63, 009, 65, 110-11 (1998). Clearly, it is reasonable to review documents prepared by the Company or the NRC to determine what the Company knew when the relevant events occurred.

These evaluations provide a picture of the operations and performance of Palo Verde going into 2005. By all accounts, as Palo Verde entered 2005, it was already experiencing a decline in performance, and over the course of 2005, Palo Verde's performance continued to decline. (Jacobs Surrebuttal at 2-3). The result of the INPO review was a level 3 rating, a mark that the Company concedes does not reflect well on the plant's performance. (Tr. at 5161-5162). In response, the Company initiated a program to improve its performance, the Performance Improvement Plan ("PIP").

The NRC issued a Midcycle Review and Inspection Plan for Palo Verde on August 31, 2006. Within the report, the NRC identified several problems and issues related to Palo Verde's decline in performance. Specifically, the report indicated that

> programmatic goals for completion of problem evaluations, consistent with industry standards were routinely not met. Ineffective and incomplete corrective actions led to a number of repeat problems that could have been prevented.

(*See* Jacobs Surrebuttal at 8). The report also expressed a concern about an apparent tendency within the Company to permit corrective responses to lapse:

> The inspectors noted instances where corrective actions were closed without completion, where repeat events occurred because of slow or ineffective corrective actions.

(*See* Jacobs Surrebuttal at 8, n.5).

These factors are relevant to the evaluation of the four outages identified as imprudent by Staff witness Jacobs. In addition, these various documents also supply a framework for scrutinizing Palo Verde's operations for purposes of determining whether a nuclear performance standard is warranted.

B. The Emergency Diesel Generator Governor Failure (March 18-21).

The Company seems to claim that, because its actions did not directly precipitate the condition leading to the outage, it was not imprudent. (APS' Br. at 164). The Company lists three probable direct causes for the introduction of the rust that caused the governor to fail. *Id.* Staff, however, believes that the Company failed to care for this equipment with the appropriate degree of care. (GDS Report at 23-24).

As Staff witness Jacobs explained, storage of the unit with oil inside it could have prevented the rust. *Id.* at 24. Indeed, the Company acknowledged that storing a governor unit with oil in the reservoir would coat the internal parts and prevent rust. (Tr. at 5139-5140). This simple and low cost measure could have been adopted, thereby preventing the outage.

APS argues that it had no reason to take this measure because it had no direct evidence that rust was forming in the governor. (APS' Br. at 165-67; Tr. at 5048-49). Staff contends that this position is unreasonable, given the importance of the emergency diesel generators. The EDGs are necessary in the event of an emergency shutdown due to loss of off-site power. (Tr. at 5140). According to NRC regulations, APS is required to shut down the unit if both EDGs are inoperable. (*See* Tr. at 5041). Certainly, APS knew that the loss of an EDG over an extended period would require a shutdown. Because each unit requires both EDGs to be operable in the event of a loss of off-site power, and because the loss of an EDG for extended periods requires shutdown of the affected unit, (Tr. at 5041), it is clear that APS did not treat the EDGs with the degree of care appropriate to the significance of this particular piece of equipment. (*See* GDS Report at 24).

Finally, Staff acknowledges that this event took place before the PSA became effective; therefore, the costs associated with this outage are not relevant to the PSA. (*See* Tr. at 5274-76).

C. Unit 1 Reactor Trip and Outage Extension Due to Operator Error (August 26-28, 2005).

In its brief, the Company claims that the intervening choices of one of its employees supersedes managerial oversight. (APS' Br. at 160-61). This argument is not persuasive. It is the Company's obligation to manage and oversee the conduct of its employees, and it ultimately must bear responsibility for the consequences of their choices. The NRC was clear that there exists a problem at Palo Verde regarding communication between management and personnel:

> These concerns were associated with not having sufficient personnel to accomplish long-term improvements, *a loss of trust that management would not subject the staff to negative consequences for raising issues, some confusion about when to place an adverse condition into [the Company's] corrective action program, and a decrease in confidence that the corrective action program will adequately address problems.*

(Jacobs Surrebuttal at 8 (emphasis added)).

As Staff witness Jacobs explained, Palo Verde's management knew that employees believed that the digital feedwater control system did not operate correctly. *Id.* at 22. During 2005, the Company had numerous opportunities to observe this phenomenon as it experienced an unusual number of reactor startups. *Id.* at 22-23. The Company understood that a common mindset of anticipated system failure existed, yet the Company failed to take the steps necessary to eliminate this mindset. This failure to address a known problem supports the conclusion that this outage is imprudent.

D. Unit 2 and 3 Refueling Water Tank Inoperability (October 11-20, 2005).

In its opening brief, the Company focuses on the distinction between a "static" evaluation of the issue as opposed to a "dynamic" one. The Company should nonetheless have anticipated this issue because of the NRC's yellow finding in 2004 on a related issue. (*See* Jacobs Surrebuttal at 24-25). The yellow finding in 2004 resulted from empty containment sump piping, thereby raising concerns that air entrainment from the empty sump piping could damage safety related pumps. The Company had reason to be aware that the air entrainment issue, including the "dynamic" air entrainment issue, was a potential concern.

In 2004, the NRC performed an inspection and issued Palo Verde a yellow finding owing to dry sump pipes. (GDS Report at 32). In response to the issue, the Company initiated an extent of condition review. The review included in its scope the RWT ECCS; as a result of that review, the Company concluded that the condition was not problematic. However, when the NRC returned and asked about dynamic air entrainment of the RWT ECCS, the Company was unable to respond beyond relying on conformity with Palo Verde's design basis. (Tr. at 4911-15). APS witness Mattson acknowledges that it was known that the proper calculation was a dynamic one thirty years ago when Palo Verde was first approved.

> You know, we knew that it was dynamic when we did the static calculation 30 years ago, but 30 years ago dealing with two component flow in this configuration, we didn't know how to do it. It's a new technique that was used when Palo Verde was shut down to be able to answer the question to justify the plant being started up again.

Id. at 4915-16.

The Company has continuing difficulties in applying a sufficiently broad scope to analyze problems. The NRC stated as much in its Fourth Quarter 2005 Reactor Oversight Program Action Matrix Summary, attached to the GDS Associates Report. In notes 5, 8, and 11, the NRC specified that the yellow finding for the 2004 violation was continued on the basis that "not all of the licensee's root and contributing causes were fully developed, many of the corrective actions were narrowly focused or ineffective, and effectiveness reviews were not adequate."

The Company argues that, if it had anticipated the air entrainment issue, it would have been obliged to shutdown the facility, thereby forcing an outage. Staff disputes this point. At the hearing, Dr. Jacobs, when asked that question, provided the following response:

> There's a difference between the company finding an issue and an NRC inspector identifying an issue. I think that if sometime earlier if the company had identified this issue and said, we may have a problem here, we're not sure, they could have gotten the time potentially to resolve it without having to shut the plant down. That's not -- you know, you never really know until it happens.
>
> There's a couple of mechanisms. They can declare the RWTs to be operable but nonconforming. And I'm thinking the Kewaunee plant here has been mentioned, and there was a similar outage up there where actually the NRC identified a problem, and they took about 12 to 14 days to evaluate it before they -- and in that case the plant actually did shut down, but there was a period of time where they were evaluating it where they didn't immediately have to shut it down because, really, the issue is you're not sure if it's operable or not.
>
> So there's also the possibility that you can ask the NRC for exemption. That we have this problem, we think it will be solved in three or four days, can we have that period of time to work on it and resolve it? So I think there's a possibility that they may not have to have it shut down.
>
> The other issue is regarding the regulatory margin that we talked about. If you're in the Palo Verde situation and an issue like that comes up, the NRC is probably going to be reluctant to give you any exemption to the time period. But if you were, you know, a top performing plant, you might have a better chance of not having to shut down. So there's a chance that they wouldn't have had to shut down. I can't say definitively one way or the other.

(Tr. at 5343-44).

The Company should have known that air entrainment damage to pumps is a safety concern and should have defined its analysis of the issues related to the yellow finding in a manner that would encompass all similar issues. Draining down the RWT gives rise to the same air entrainment concerns as the empty sump piping, and APS' failure to identify this issue demonstrates a lack of rigor in its analysis.

In surrebuttal, Staff witness Jacobs pointed out that the NRC had already identified numerous crosscutting issues, *i.e.*, issues affecting several areas of plant organization:

> Crosscutting themes identified in this component involved inadequate evaluations of problems and untimely implementation of corrective actions. Examples include: failures to address the extent of condition of problems; failures to fully evaluate problems resulting in repetitive or long-standing problems affecting safety systems and components; failures to correct known degraded conditions in a timely manner. The crosscutting themes identified during this assessment are similar to those that have been identified in previous NRC assessments,

> particularly with respect to inadequate evaluation of conditions adverse to quality, as well as inadequate and effective correction of problems.

(*See* Jacobs Surrebuttal at 11-14). This evaluation notes APS' failure to fully evaluate issues that cut across multiple facets of plant operations.

APS knew or should have known that air entrainment issues in the RWT were raised by the 2004 yellow finding, and APS knew or should have known that its problem identification and analysis tended to be too narrowly focused. A reasonably complete analysis of the issues related to the 2004 yellow finding would have permitted the Company to identify this issue. *Id.* at 24-25. This outage was therefore avoidable and imprudent.

<u>E.</u> <u>Measuring the Impact.</u>

In addition to disputing the imprudence of the previously discussed outages, the Company's brief raises several issues related to measuring the costs of imprudence.

1. Offsetting coal operations against the Impact of Palo Verde Outages is not Reasonable.

The Company argues that the strong performance of its coal plants mitigates the costs of the imprudent outages. (APS' Br. at 149). This contention is unpersuasive. The improved performance of APS' coal generation is not related to the Palo Verde outages, and the fact of improved performance of the coal plants highlights the loss of Palo Verde, which could have had excess power to sell off-system.

The Palo Verde outages should be considered in isolation. In spite of the improved performance of the coal plants, this improved performance did not prevent the costs incurred by the Palo Verde outages. The Company's brief seems to imply that, without the Palo Verde outages, the improved performance of the coal plants would not have occurred. (*See* APS' Br. at 175) The Company, however, supplied no testimony to the effect that the improved performance of its coal plants was caused by the Palo Verde outages or was in any way connected with the outages.

The calculation of the costs of the outages of necessity nets the cost impact on the entire system. The impact of the improved performance of the coal plants was already counted in the system balancing that still necessitated purchasing replacement power. (Jacobs Surrebuttal at 45). Consequently, the improved performance of the coal plants should not be considered as a mitigating factor because it is unrelated to the Palo Verde outages and would result in double counting.

2. Lost Off-System Sales.

In its opening brief, the Company concedes that the outages have decreased off-system sales, but the Company disagrees with Staff's calculation of the measure of these lost sales. (APS' Br. at 175). In developing its testimony, Staff asked the Company provide additional information to support APS' proposed adjustments to reflect margins related to lost off-system sales. (Jacobs Surrebuttal at 41). In response, the Company provided the results that it developed using a production cost model. Although the Commission has approved the use of this methodology before, Staff is concerned about the inputs chosen by the Company in its analysis. As Staff witness Jacobs explained,

> [Y]ou have the model, and then you have the application of the model. And just because the model has been accepted, that doesn't mean that in any particular application, given all of your assumptions going into it, that your answer is going to be correct.

(Tr. at 5312). In surrebuttal, Staff had already expressed concerns about the inputs chosen by the Company in its analysis.

Principally, Staff focused on the improbability of two significant assumptions that the Company made in its analysis. First, the Company assumed that the lost sales would occur only during the times when Palo Verde was shutdown due to an imprudent outage. (Jacobs Surrebuttal at 41). Second, the Company assumed that APS was not buying power in the wholesale market. *Id.* Staff contends that neither assumption is reasonable because the outages may be the events that caused APS to purchase wholesale power. *Id.* at 41-42. Further, the analysis appears to incorporate errors. For example, it assumed lower off-system sales when Palo Verde was operating than when it was out-of-service. And in some circumstances, the simulation produced lower margins even though the level of lost generation in off-system sales increased. *Id.* at 42. Clearly, the Company's analysis introduces more questions than it resolves in terms of the quantification of margins on lost off-system opportunity sales. Consequently, Staff's position on the amount of lost off-system sales should be adopted.

3. The Nuclear Performance Standard is an Appropriate Responsive Measure.

In response to the ongoing issues regarding Palo Verde's decline in performance, Staff recommends that the Commission create a Nuclear Performance Standard ("NPS"). The Company, in its opening brief, expressed several reservations about such a plan. The Company suggests that the plan should include incentives as well as caps on penalties so as not to jeopardize the Company's attention to safety. (APS' Br. at 168-169, 171-175). The Company also believes that coal generation should be included in the implementation of any performance standard. *Id.* at 173-174. Finally, the Company believes that more information is necessary to implement a NPS than has been developed to date. *Id.* at 169-71.

The Commission should adopt a performance standard to govern the operation of Palo Verde. The Company will recover its cost of invested capital regardless of the quality of its performance, and the ratepayers therefore bear the risk of poor performance. (Jacobs Surrebuttal at 35). This is unfair when one considers that nuclear plants have exceptionally high capital costs and that only the low costs of fuel and operations offset the high capital costs. The lower cost of operations can only be achieved when the plant operates at a high capacity factor. Adopting a reasonable NPS will alleviate this situation by placing the costs of inefficient operations on both the Company and its ratepayers. (Tr. at 5128, 5225).

Staff's proposed NPS is reasonable and does not jeopardize safety. Dr. Jacobs explained that incentives rarely influence a company in a positive manner and therefore typically end up subsidizing a company for unchanged behavior. (Jacobs Surrebuttal at 35). As to dead bands and penalty caps, Staff's proposed NPS already incorporates a three-year sampling for evaluations. Consequently, the plan provides an added buffering influence of several years of performance to alleviate the impact of an atypical year. (*See* Jacobs Surrebuttal at 37).

With respect to the Company's proposal to include all base load generation in the performance plan, Staff believes that such an all-inclusive plan would not serve any useful purpose. Coal and nuclear power are fundamentally different. (Jacobs Surrebuttal at 36). Their fixed and variable costs are largely reversed, and their methods of operation and basic regulatory regimes are fundamentally different. A broad performance standard encompassing the Company's entire baseload generation would permit the Company to gloss over the performance of its single most costly asset, Palo Verde.

In response to the Company's concerns regarding the lack of specificity contained in the NPS, Staff has acknowledged that the NPS may be subject to various modifications that the Commission may elect to make. *Id.* at 38. However, as Dr. Jacobs testified, Staff's proposed NPS is sufficiently detailed to implement as written. *Id.* at 38-39.

XII. ENVIRONMENTAL IMPROVEMENT CHARGE

Among its arguments in support of its proposed environmental improvement charge ("EIC"), APS notes that its proposal is not a contribution in aid of construction, but is instead more analogous to CWIP. (APS' Br. at 100). Staff disagrees with this characterization.

The proposed EIC is certainly novel and is therefore somewhat difficult to precisely categorize. Nonetheless, the proposed EIC is designed to entirely recover many of APS' costs—including capital costs—in advance, thereby eliminating the need for APS to actually make an investment before recovering the costs of that investment. The following testimony illustrates this potential:

Q. [U]nder your proposal is it intended that the EIC will be collected before some of the costs are incurred?

A. The EIC is intended, again, to collect costs that are anticipated to be incurred over the forecast period.

Q. So the answer to my questions is yes, I think?

A. Yes, subject to true up.

Q. Does the EIC provide a means for APS to earn a return on projects before they're actually rate-based?

A. Yes.

Q. Does the EIC provide a means for APS to earn a return on a project before it has begun?

A. Possibly.

(Tr. at 2489-90). In some respects, the proposed EIC is akin to ratepayer-supplied capital, yet APS' proposal does not appear to provide any recognition of this principle. For example, APS' proposed EIC does not include provisions for appropriate rate base deductions to give ratepayers some benefit for having supplied capital. The proposed EIC is therefore somewhat one-sided, and Staff believes that this design is not equitable. For this reason, Staff believes that the Commission should reject APS' proposed EIC.

XIII. DEMAND SIDE MANAGEMENT

APS once again argues that it should be allowed to recover its proposed "conservation adjustment" for revenues lost as a result of its DSM programs. (APS' Br. at 69). Staff maintains its position that such a pro-forma adjustment should not be allowed because the revenue reduction is not known and measurable. (Anderson Surrebuttal at 7). Staff believes that APS should be compensated for its efforts to make DSM programs available and for the savings achieved by those programs through a performance incentive. (Anderson Direct at 9).

APS also states that the Company proposes, and SWEEP and Staff agree, that any unspent funds should be carried over and spent in subsequent years." (APS' Br. at 118). Staff would like to clarify that it does *not* agree that unspent funds should be carried over and spent in subsequent years. Staff stated clearly that, if during 2005 through 2007, APS does not spend at least $30 million of the base rate allowance for approved and eligible DSM-related items, the unspent amount is to be credited to the account balance of the Demand Side Management Adjustment Clause ("DSMAC") account. (Anderson Surrebuttal at 2). These are monies paid by APS' customers through base rates. If the $30 million collected in this manner has not been spent during the 2005 through 2007 period, then it should be given back to the customers who paid it. (Tr. at 3634).

XIV. POWER SUPPLY ADJUSTER

Staff continues to oppose the inclusion of broker fees in the power supply adjuster ("PSA"). At the hearing, Staff witness Antonuk explained the reasons for excluding broker fees:

> [M]y understanding is that the Staff who worked on the PSA the last time was comfortable in the conclusion that there had been a removal of them. So I treated that as precedent, you know. It was established. That was the rule. So this reflects the rule.

(Tr. at 4009). Staff considered the exclusion of broker fees to be established precedent, and therefore adopted a consistent position in this case.

XV. RATE DESIGN

Concerning Rate E-32, Staff has noted its hesitation to raise demand rates significantly over levels proposed by APS. (Staff's Br. at 66). This concern is prompted by two factors: 1) the last rate case significantly raised the demand charge for customers above 20 kW so that some lower load factor customers received increases significantly greater than the system average increase; and 2) this adoption of a higher demand rate is fairly new in that current rates have only been in effect for approximately eighteen months.

This same concern is also applicable to a rate proposal sponsored by AECC witness Higgins. Specifically, AECC proposes to pass through the transmission charge in the demand portion of Rate E-32. Entirely aside from the possible cost-of-service merits of this proposal, Staff is concerned that it will result in a substantial rate increase to a segment of APS' customers who have recently experienced rate increases that are significantly greater than the system average. In order to promote the principle of gradualism in rate design, Staff opposes this AECC proposal at this time.

XVI. DEMAND RESPONSE

Staff has recommended that APS conduct a study to identify the types of demand response and load management programs that would be most beneficial to APS' system. Staff has also recommended that APS file for Commission approval one or more cost effective demand response or load management programs. Staff has suggested that both of these items should be filed with the Commission within eight months of a Commission decision in this matter. If APS needs more than eight months to complete these filings, Staff would not object to extending the deadline.

In its brief, APS appears to misunderstand these proposals. APS states that, "[a]lthough Staff has proposed an eight-month feasibility study, the Company believes that truly effective Demand Response programs cannot be implemented, analyzed, and introduced to all customers in such a short amount of time. (APS' Br. at 123). Staff wishes to clarify that its proposal does not envision full implementation and introduction "to all customers" within an eight-month period. Instead, Staff intended for the study and associated programs to serve as a means to initiate consideration of these issues. In any event, Staff is not opposed to extending the due date for these filings beyond eight months.

XVII. MISCELLANEOUS ISSUES

There are a number of items that APS has proposed *after* the filing of its direct case:

1) In rebuttal testimony, APS proposed a number of changes to various partial requirements tariffs as well as a number of proposed new partial requirements tariffs. (APS' Br. at 95-99).

2) After the conclusion of the hearing, APS provided a late-filed exhibit related to one of its proposed solar schedules.

3) In its brief, APS has proposed the creation of a regulatory asset/liability in connection with the $4.25 million incremental EPS surcharge. (APS' Br. at 94).

4) In its brief, APS has proposed authorization of an alternative funding mechanism for investments related to its Advanced Metering Infrastructure proposal. (APS' Br. at 134).

Because these issues were raised comparatively late in the proceeding, Staff has not fully analyzed them and is therefore unable to offer an opinion at this time.

XVIII. CONCLUSION

For these reasons, Staff requests that the Commission adopt Staff's recommendations in this matter.

RESPECTFULLY SUBMITTED this 16th day of February, 2007.

Christopher C. Kempley, Chief Counsel
Janet Wagner, Senior Staff Counsel
Charles Hains, Attorney
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007
(602) 542-3402

Original and 17 copies of the foregoing filed this 16th day of February, 2007, with:

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, AZ 85007

Copy of the foregoing mailed this
16th day of February, 2007 to:

Deborah R. Scott
Kimberly A. Grouse
SNELL & WILMER
One Arizona Center
400 East Van Buren Street
Phoenix, AZ 85004-2202

Thomas L. Mumaw
Karilee S. Ramaley
PINNACLE WEST CAPITAL
CORPORATION
Post Office Box 53999, MS 8695
Phoenix, AZ 85072-3999

C. Webb Crockett
Patrick J. Black
FENNEMORE CRAIG, P.C.
3003 North Central Avenue, Suite 2600
Phoenix, AZ 85012-2913

Michelle Livengood
UniSource Energy Services
One South Church Street, Suite 200
Tucson, AZ 85702

Steven B. Bennett
Deputy City Attorney
City of Scottsdale
City Attorney's Office
3939 North Drinkwater Boulevard
Scottsdale, AZ 85251

George Bien-Willner
3641 North 39th Avenue
Phoenix, AZ 85014

Michael W. Patten
J. Matthew Derstine
Laura E. Sixkiller
ROSHKA DEWULF & PATTEN, PLC
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, AZ 85004

Michael L. Kurtz
BOEHM, KURTZ & LOWRY
36 East Seventh Street, Suite 1510
Cincinnati, OH 45202

Scott S. Wakefield
RUCO
1110 West Washington Street, Suite 220
Phoenix, AZ 85007

Lawrence V. Robertson, Jr.
Post Office Box 1448
Tubac, AZ 85646

Bill Murphy
Murphy Consulting
5401 North 25th Street
Phoenix, AZ 85016

Andrew W. Bettwy
Karen S. Haller
Assistants General Cunsel
Legal Affairs Department
5241 Spring Mountain Road
Las Vegas, NV 89150

Amanda Ormond
The Ormond Group LLC
Southwest Representative
Interwest Energy Alliance
7650 South McClintock, Suite 103-282
Tempe, AZ 85284

Joseph Knauer, President
Jewish Community of Sedona
and the Verde Valley
100 Meadowlark Drive
Post Office Box 10242
Sedona, AZ 86339-8242

David C. Kennedy, Esq.
818 East Osborn Road, Suite 103
Phoenix, AZ 85014

S. David Childers, Esq.
LOW & CHILDERS
2999 North 44th Street, Suite 250
Phoenix, AZ 85018

Tracy Spoon
Sun City Taxpayers Association
12630 North 103rd Avenue, Suite 144
Sun City, AZ 85351

Tammie Woody
10825 West Laurie Lane
Peoria, AZ 85345

Douglas V. Fant
Law Offices of Douglas V. Fant
3655 West Anthem Drive, Suite A-109
Anthem, AZ 85086

Gary Yaquinto, President
Arizona Utility Investors Association
2100 North Central Avenue, Suite 210
Phoenix, AZ 85004

Sein Seitz, President
Arizona Solar Energy Industries Association
3008 North Civic Center Plaza
Scottsdale, AZ 85251

Dan Austin
Comverge, Inc.
6509 West Frye Road, Suite 4
Chandler, AZ 85226

Timothy M. Hogan
Arizona Center for Law in the Public Interest
202 East McDowell Road, Suite 153
Phoenix, AZ 85004

Jay I. Moyes
Moyes Storey Ltd.
1850 North Central Avenue, Suite 110
Phoenix, AZ 85004

Kenneth R. Saline, P.E.
K.R. Saline & Assoc., PLC
160 North Pasadena, Suite 101
Mesa, AZ 85201

Robert W. Geake
Vice President and General Counsel
Arizona Water Company
Post Office Box 29006
Phoenix, AZ 85038-9006

Lieutenant Colonel Karen S. White
Chief, Air Force Utility Litigation Team
AFLSA/JACL-ULT
139 Barnes Drive
Tyndall AFB, FL 32403

Greg Patterson
Arizona Competitive Power Alliance
916 West Adams Street, Suite 3
Phoenix, AZ 85007

Jim Nelson
12621 North 17th Place
Phoenix, AZ 85022

Michael M. Grant
Gallagher & Kennedy, P.A.
2575 East Camelback Road
Phoenix, Arizona 85016-9225

Barbara Klemstine
Brian Brumfield
Arizona Public Service
Post Office Box 53999, MS 9708
Phoenix, AZ 85072-3999

Jon Poston
AARP Electric Rate Project
6733 East Dale Lane
Cave Creek, AZ 85331

Coralette Hannon
AARP Government Relations & Advocacy
6705 Reedy Creek Road
Charlotte, NC 28215

Roseann Osorio